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Compliance Assurance and Enforcement Division

OSAGE OPERATOR'S ENVIRONMENTAL REFERENCE MANUAL

Written Cooperatively by:

Osage Tribal Council
Osage Producers Association
Environmental Protection Agency
Bureau of Indian Affairs, Osage Agency

June 1997
Draft

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Emergency Numbers

Internal Notification Numbers

1. ______________________ Telephone Number: __________

2. ______________________ Telephone Number: __________

External Notification Numbers

1. National Response Center	800-424-8802
2. Osage UIC Office (EPA)	918-287-4041
3. Osage Bureau of Indian Affairs	918-287-1351
4. Osage Tribal Council	918-287-1085
5. Local Emergency Planning Committee	918-287-3980
6. Local Responders (Police, Fire, Ambulance)	911

Emergency Response Contractors

1. ______________________ Telephone Number: __________

2. ______________________ Telephone Number: __________

Clean-up Contractors

1. ______________________ Telephone Number: __________

2. ______________________ Telephone Number: __________

Supplies and Equipment

1. ______________________ Telephone Number: __________

2. ______________________ Telephone Number: __________

Introduction

Since the early 1970's, there have been many new local, State and Federal laws that govern our businesses and personal lives involving the use of land, water and air. The penalties for failing to comply with environmental law can be extremely high; therefore, we feel it is necessary for petroleum industry professionals to educate themselves about these many laws and regulations.

This environmental handbook has been compiled for you by the following organizations: Osage Tribal Council, Osage Producers Association, Bureau of Indian Affairs, and the Environmental Protection Agency. An Osage Operator's Environmental Handbook was published at the same time this manual was published, which has summary information that you can use to quickly determine environmental requirements. We hope the information provided will be useful in your daily responsibilities of production, protection and preservation. We must also place the following disclaimer on this document since environmental rules and regulations are changing so rapidly, and are subject to interpretation by each office of the enforcement agency.

This manual has been prepared to assist those who must comply with the environmental regulations of Oklahoma and the Federal Government. HOWEVER, the individuals who participated in the compilation of the information in this manual and all of their employers disclaim all warranties, express or implied. This manual is not a legal document. The text and advice contained herein should be reviewed by your legal and other professional advisors before any use and reliance thereon. Such review should extend to the applicable statutes, regulations, and judicial developments in effect and as developed by each jurisdiction up to the time of taking any action in this complex, rapidly changing field.

I. Spill Reporting and Agency Contacts

A. Spill Reporting

1. All spills of oil and/or saltwater must be reported to the Osage Agency (918-287-1351).

2. Any spill of oil and/or saltwater which enters or threatens a waterway (waters of the United States) must be reported to the Osage UIC office (918-287-4041).

3. Any **oil** spill which enters or threatens a waterway (waters of the United States) must be reported immediately to the National Response Center (1-800-424-8802).

B. Injection Well Requirements

1. For Information on:

   a. How to apply for a permit
   b. How to complete a permit application
   c. Draft UIC Permits
   d. To comment on draft permits contact either of the following:

   Osage UIC Office
   Post Office Box 1495
   Pawhuska, OK 74056
   Phone: 918-287-4041

   Groundwater/UIC Section
   Environmental Protection Agency
   1445 Ross Avenue
   Dallas, TX 75202
   Phone: 214-665-7165

2. For Information on:

   a. Compliance with UIC requirements or permit conditions
   b. Regulation or permit requirements
   c. Compliance schedules or enforcement orders
   d. Inspection policies/procedures
   e. Ongoing investigations

   Osage UIC Office
   Post Office Box 1495
   Pawhuska, OK 74056
   Phone: 918-287-4041

   AR/LA/OK NPDES (UIC) Section
   Environmental Protection Agency
   1445 Ross Avenue
   Dallas, TX 75202
   Phone: 214-665-6470

C. For information on Spill Prevention and Countermeasures Program (Requirements for Berms around Tank Batteries), contact:

Preparedness and Prevention Team
Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202
Phone: 214-665-6485

1. To report an oil spill to a surface stream call: 1-800-424-8802

2. For local assistance call:

Osage Agency: 918-287-1351
Osage UIC Office: 918-287-4041

D. For information on Osage Agency Requirements, contact:

Minerals Branch
Osage Agency
Post Office Box 1532
Pawhuska, OK 74056
Phone: 918-287-1351

II. Clean Water Act Requirements

A. Clean Water Act Requirements

The Clean Water Act (CWA) is the major Federal law which protects surface waters in the United States. This is accomplished by implementing regulations, permits, and the law. Those portions of the CWA which impact oil and gas exploration and production activities include:

Section 301 - Prohibits the unauthorized discharge of pollutants into waters of the United States.

Section 308 - Provides the Environmental Protection Agency (EPA) with the ability to inspect facilities and to require submission of sampling information.

Section 309 - Provides the EPA with the authority to issue administrative orders, administrative penalties, or initiate civil action for violations of the CWA.

Section 402 - Establishes a permit program to regulate or prohibit discharges of pollutants into waters of the United States. (The permit system established by this portion of the Act is referred to as the National Pollutant Discharge Elimination System (NPDES) program.)

For oil and gas production wells which produce less than 10 barrels of oil per day, the requirement that is enforced is the general prohibition under Section 301 of the Act, which prohibits the discharge of pollutants into waters of the United States. Producing wells which produce more than 10 barrels of oil per day or have produced more than 10 barrels of oil per day at any time since March 25, 1991, are subject to the general permit for onshore oil and gas production facilities.

B. Waters of the United States

The discharge of brine, drilling fluids, muds and oil to waters of the United States is generally prohibited. Significant civil and criminal penalties may result from such discharges. "Waters of the United States" is a very broad term intended to include most surface waters physically located in the United States. Under EPA's regulatory definition (40 C.F.R. §122.2), even a small isolated waterbody is a water of the United States if its "use, degradation, or destruction...would affect or could affect interstate or foreign commerce."

Determining whether a specific small waterbody meets that definition is frequently difficult, particularly in the field. From looking at a farm pond, for instance, one might not be able to tell whether livestock which drink from it are sold at an auction attended by interstate buyers or whether it is used by migratory birds like ducks. Either of those circumstances, however, is legally sufficient to show the pond is a water of the United States. To avoid potential liability for violating the law, oil and gas operators should thus avoid discharging to any surface waterbody, no matter how small or insignificant it might look. Even if EPA later decides it has no jurisdiction, avoiding such discharges may also avoid disagreements and possible litigation with surface owners.

III. Injection Well Requirements

A. Annual Operation Reports

1. Injection well operators must submit an annual report of injection activities to the Environmental Protection Agency.

2. The EPA sends a notice and report forms when the report is due. The date that the report is due depends on where the well is located. The following shows report due dates by well location:

Township/Range Location	Report Due Date
Townships 20 North - 23 North Ranges 6 East - 12 East	January 31
Townships 27 North - 29 North Ranges 5 East - 12 East	April 30
Townships 24 North - 26 North Ranges 2 East - 7 East	July 31
Townships 24 North - 26 North Ranges 8 East - 12 East	October 31

3. Report must include the following:

   a. Average and Maximum injection pressure during the month.

   b. Total barrels of fluid injected during each month.

   c. Average and maximum annulus pressure if using annulus monitoring to demonstrate mechanical integrity or the permit requires annulus monitoring.

   d. Information required by UIC permit (See permit for specific requirements):

      i. Production in area of injection well.

      ii. Fluid levels in area of injection well.

      NOTE: There are no EPA forms to report this data. The permittee must develop their own format.

   e. Inactive wells may require fluid level monitoring information.

4. Keep actual records of monitoring (pumper's log, actual charts, etc.) for three years after the report is completed. Also, keep copy of the submitted report in your file for three years.

B. Conversion to Production

1. Any injection well may be converted to production use at any time. When conversion is complete jurisdiction reverts to the BIA.

2. The well operator must demonstrate that conversion has actually been completed.[1]

   a. Obtain conversion permit from the BIA.[1,2]

   b. Complete physical conversion of well (i.e., install rods and tubing, pump jack and motor and begin production).

   c. Submit Osage Form No. 139 to both the BIA and the EPA UIC office that shows conversion to be complete.

3. EPA inspects well to verify conversion.

4. <u>If a well is swabbed for production</u>, the operator must (in addition to the items listed above) notify the EPA by letter of the production method and submit a copy of the first lease status report after conversion to verify the amount of oil being produced.[1]

5. <u>If the well is authorized by permit</u>, the permit remains in effect until the permittee requests permit termination. As long as the permit is in effect, the well can be converted back to injection at any time. Before actual injection takes place, the operator must demonstrate that the well has mechanical integrity.[1]

6. The EPA notifies the well operator before amending its records to show that a well is converted to production. If the well is being tested for production and may be converted back to injection within a short time (e.g., two months), notify EPA.[1]

C. Lease Transfer Procedures

1. All Injection Wells

   a. Before purchasing a lease, check with the BIA and EPA to verify that the lease is compliant with BIA and EPA requirements.[3]

   b. After purchasing a lease, be sure to obtain all pertinent records of well construction and operation from the seller.[3]

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1 Required by Environmental Protection Agency regulation or policy

2 Required by Bureau of Indian Affairs regulation or policy

3 Recommended good operating practice

c. After completing the transfer:

i. Purchaser must submit a signed lease assignment (BIA Form F) and a copy of the bond to the BIA.[2]

ii. Seller should submit required operation report to EPA for the portion of the report period that he owned/operated the well.[3]

d. The assignment form shows the effective date of the transfer. The seller is responsible for all reporting, monitoring, and violations of program requirements until the effective date of transfer. The buyer is responsible for the lease after the effective date of transfer.[1,2]

2. <u>If the well is authorized for injection by EPA by rule,</u> seller and purchaser should notify the EPA of the lease transfer. The notice may be a copy of the lease assignment and bond sent to the BIA.[3]

3. <u>If the well is authorized for injection by the EPA by permit,</u> the seller must notify the EPA of the lease transfer.[1] The notice may be a copy of the lease transfer and the bond sent to the BIA.

D. Mechanical Integrity Testing

1. Well must have mechanical integrity before being used for fluid injection.[1]

2. Notify EPA at least five days before testing a well so an EPA representative can witness the test.[1]

3. Two parts of mechanical integrity demonstration:[1]

a. Prove that there will be no significant fluid movement behind casing.

i. This is generally determined by reviewing well construction records. Specific construction requirements depend on when the well was drilled.

ii. Table 1 summarizes construction requirements.

b. Prove that there would be no significant leaks in the casing, tubing, or packer. Types of tests and requirements are shown in Table 2.

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1 Required by Environmental Protection Agency regulation or policy

2 Required by Bureau of Indian Affairs regulation or policy

3 Recommended good operating practice

Table 1
Well Construction Requirements

Date Well Drilled	Casing and Cementing Requirements
Pre-April 1953	Cemented casing through all underground sources of drinking water OR Cemented casing 100 feet above the injection formation
April 1953 - December 1984	1. Cemented casing through water with less than 3000 mg/l total dissolved solids. 2. Cemented casing 100 feet above injection formation
After December 1984	1. Cemented casing at least 50 feet below water with less than 10,000 mg/l total dissolved solids. 2. Cemented casing 100 feet above the injection zone

4. Fluid Returns after Mechanical Integrity Test.[1]

   a. Last step of mechanical integrity test.

   b. Used by engineer to estimate packer depth.

   c. Amount of fluid return depends on:

      i. Annulus fluid type.

      ii. Tubing and casing materials and size.

      iii. Time since annulus filled.

      iv. Injection during the test.

      v. Temperature of injected or annular fluids.

      vi. Packer depth.

1 Required by Environmental Protection Agency regulation or policy
2 Required by Bureau of Indian Affairs regulation or policy
3 Recommended good operating practice

Table 2
Mechanical Integrity Test Requirements[1]

Test Options	Procedures	Comments
Casing-Tubing Annulus Pressure Test	1. Apply pressure of 200 psi to annulus. Annulus pressure must be at least 100 psi different from tubing pressure (Applied pressure may be less than 200 psi if required for 100 psi differential, but not less than 100 psi) 2. Monitor pressure for 30 minutes 3. Release pressure and measure fluid returned	1. Must verify packer depth by calculation based on fluid returns at end of test 2. Pass if packer depth adequate and pressure loss no more than 10%
"Ada" Pressure test	1. Determine the static fluid level in the well 2. Calculate required test pressure 3. Apply gas (usually nitrogen) pressure to force fluid into the perforations 4. Monitor pressure for 30 minutes	1. Can be used to test well with no tubing and packer 2. Can determine the depth of casing leaks 3. Pass test if pressure stays in predicted range
Annulus Monitoring (e.g., "Barrel Test")	1. Fill the casing with fluid and continuously maintain a positive pressure on the well annulus 2. Monitor the pressure monthly 3. Report annulus pressure to the EPA with the annual operation report	1. Cannot use if failed a pressure test 2. Fail test if pressure drops to "0" or must frequently add fluid to maintain pressure or fail to report monitoring results 3. Require pressure test if fail
Continuous Fluid Level Monitoring (e.g., "Osage Sentry")	Discuss with EPA Engineer	1. Continuously monitor to assure that annulus fluid level is below base of USDW 2. May be used for wells with tubing and packer integrity but casing leaks
Radioactive Tracer Survey	Discuss with EPA Engineer	

1 Required by Environmental Protection Agency regulation or policy
2 Required by Bureau of Indian Affairs regulation or policy
3 Recommended good operating practice

d. If fluid returns indicate shallow packer depth, the Environmental Protection Agency engineer will require proof of packer setting depth before verifying well integrity. Verification of packer setting may include:[1]

i. Tubing tally.

ii. Tubing log.

iii. Pull tubing from hole.

5. Options for Wells That Fail Test.

a. Demonstrate mechanical integrity. Any repair that allows a satisfactory mechanical integrity demonstration is allowed. (NOTE: The use of Angaard or other materials that prevent testing the full length of casing is prohibited).[1]

b. Cease using well for fluid injection.

c. Common repair options include:

i. Cement squeeze.

ii. Concentric packer.

iii. Liner.

iv. Packer repair/replacement.

v. Cement from surface to leak.

vi. Casing patch.

vii. Replace joint of casing with leak.

viii. Replace joint of tubing with hole.

ix. Set a liner on a packer (Would require special monitoring and testing procedures. Discuss with EPA).

6. Alternative Mechanical Integrity Testing.[1]

Regulations allow approval of alternative mechanical integrity procedures. Alternative test procedures for wells authorized by permit must be approved by EPA headquarters. The process shown below has been approved by EPA for injection wells authorized by rule.

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1 Required by Environmental Protection Agency regulation or policy

2 Required by Bureau of Indian Affairs regulation or policy

3 Recommended good operating practice

a. Demonstrate mechanical integrity of the tubing and packer;

b. Install and maintain a monitoring system approved by EPA which would detect and warn of fluid level in casing/tubing annulus within 100 feet of the base of the lowest USDW;

c. Measure the static fluid level in the well annulus at least annually;

d. If the fluid level is detected within 100 feet of the USDW:

   i. Notify the EPA within 48 hours; and,

   ii. Within five (5) days, reset the monitoring device to detect the fluid level within 75 feet of the base of the USDW.

e. If the fluid level rises to within 75 feet of the USDW:

   i. Report to the EPA within 48 hours (The report must include the rate of fluid level rise in feet per day); and,

   ii. Within five (5) days reset the monitoring device to detect fluid within 50 feet of the base of USDWs.

f. If fluid rises to within 50 feet of the base of USDWs:

   i. Immediately shut in the well and report to the EPA; and,

   ii. If the fluid level remains less than 50 feet below the base of USDWs, submit a corrective action plan to the EPA.

E. Permit Procedures and Technical Requirements

1. Overview

Injection operations in Osage County, Oklahoma, are primarily for the purpose of enhancing the recovery of oil from the numerous reservoirs that underlay the county. Injection is also used for the disposal of excess produced water into a number of non-productive zones.

EPA Region 6 is charged with the direct implementation, in Osage County, of the mandates of the Safe Drinking Water Act. A team of engineers in the Ground Water/UIC Section is responsible for preparing the permits required to legally conduct those underground injection operations. The team also reviews the performance of wells that are authorized by rule to inject.

2. Regulatory Requirements

Underground injection is allowed only if it is:

a. Authorized by Rule or,

b. Permitted under the UIC program.

No underground injection may result in the movement of contaminants into an underground source of drinking water (USDW).

Details of these rules can be found in Section 2903, Part 147 of Title 40 of the US Code of Federal Regulations (40 CFR §147.2903).

3. The Permit Application Package

The permit application package provides the operator an opportunity to educate the permits engineer on the details of an injection project. The operator may post the data on the several pre-formatted documents that make up the application package.

The information is to assist the engineer in characterizing the injection system and in defining the variables that will set the operating conditions in the study area. An assessment of the risk of contamination under these operating conditions over a twenty year period will then be completed.

The following documents make up the application package for an Osage/UIC permit:

a. Osage Forms 139 and 208

b. The Well Schematic Form

c. The Well Operation and Geologic Data Form

d. The Well Tabulation

e. Map(s)

f. Other Administrative Requirements

You can obtain an application package from the Osage UIC office. More details justifying the reasons for requesting the information in the package are provided in the following sections.

4. The Permit Issuance Process

a. Emergency Permit

The UIC regulations make provisions for the issuance of emergency permits. The circumstances under which EPA may issue an emergency permit are discussed in Section 2906, Part 147 of Title 40 of the US Code of Federal Regulations (40 CFR§147.2906).

b. The Engineering Review Process

The main objective of the engineering review process is **the determination of a rate of accumulation that is environmentally safe,** and the formulation of operating conditions that will contribute to minimize the risk of contamination of the USDWs.

The rate of accumulation (or "net" injection rate) relates to the volume of injected fluids that over a number of days fails to reach the producing wells in **an enhanced oil recovery project.**

In this type of project the "net" injection rate for a well, or group of wells, may be lower than the injection rate measured at the wellhead (the "gross" injection rate). In **disposal operations,** on the other hand, all of the injected fluids remain in the reservoir.

The pressure build up effected in the reservoir by the accumulation of injected fluids must not result in the movement of these into a USDW.

For a given period of operation, **the estimated rate of accumulation of injected fluids is a function of a number of variables.** Some of these variables are the result of decisions made by the operators and some are intrinsic to the reservoir.

The following discussion on the stages of the engineering evaluation identifies several of those variables.

i. Understanding the Reservoir Flow System on Hand

The analysis of a reservoir flow system usually starts with a review of maps for the area of interest. In the Osage/UIC program, the type of map more frequently available to the engineer is **the location map.**

The location map provides, at a minimum, visual information on the **well population and distribution.** These two important factors have great potential for impacting the reservoir flow pattern and, by default, the allowable rate of accumulation for a given period of operation.

The information on the provided map is usually complemented with other information from the application package in order to establish **the number of improperly completed and improperly plugged and abandoned (P&A'd) wells.** It is equally important that the map identify the type of each remaining well in the area under study.

It is very likely that the larger the number of injection wells in a given reservoir, the lower the environmentally safe rate of accumulation for each well will be (if all other variables remain the same).

ii. Identifying Points With Endangerment Potential

Points with potential for endangerment within a study area are those locations at which the injected fluids could leak out of the injection zone and enter a USDW.

In the Osage/UIC program the most frequently found avenues for the vertical movement of injected fluids are **improperly completed** and **improperly plugged and abandoned wells.** Appendix B illustrates, with well schematics, the requirements for proper plugging and abandonment of wells.

(1) Improperly Completed Well - A well is considered improperly completed if:

- o The surface casing was not cement circulated;
- o The surface casing was cemented but its shoe was not set at least 50 feet below the base of the USDWs;
- o The production casing string was not cemented;
- o The cement column rises less than 100 feet above the top of the injection interval; or,

- o The well has sections of uncemented casing opposite intervals that are the injection zones in neighboring wells.

(2) The Improperly Plugged and Abandoned (P&A'd) Well - The following are examples of frequently found improperly plugged and abandoned wells:

- o An open hole filled only with mud and debris;
- o The production casing was ripped above the top of the cement and then pulled out, and the hole is filled with mud;
- o There is no cement behind the production casing, though it was left in the hole and was filled with alternating cement plugs and mud slugs;
- o The cement plugs are too small or are too close to the surface, above the base of the USDWs; or
- o No information is provided on the plugging procedure.

iii. Estimating the Base of the USDWs

Of two wells that have identical completion and reservoir characteristics but different **depth to the base of the USDWs,** the one with the deeper base will be permitted at a lower rate of accumulation. Following are two approaches that the permits team may use to estimate the base of the deepest fresh water sand.

(1) Fresh Water Supply Well Inventory - The EPA regional office has available a database providing information on the ownership, location and completion of a number of private fresh water supply wells in Osage County, Oklahoma. This database can be searched for the purpose of establishing the depth of fresh water sands being produced in a study area. Though it is not certain that the depth information obtained through these means may correspond to the base of the USDWs, the information may prove valuable in assessing endangerment risk in the absence of any other data.

(2) An Approximate Empirical Approach - Ideally, an electric log run through the fresh water sands will be available for the well of interest. If such log is not available, as is usually the case in the Osage/UIC program, a log from a neighboring well will be used. The analysis of such log is possible using the SPLOG Basic program, available to the permits engineers. This approach may not be used if the well was air drilled. The log from such well, however, may still be used to qualitatively estimate the base of the USDWs through eyeballing.

iv. Estimating the Reservoir Pressure

The estimated rate of accumulation will be lower for the well with the larger **reservoir pressure** (when the same period of operation and identical remaining parameters are assumed). The permits team usually performs estimates of the reservoir pressure using field data. The following illustrates some of the sources for these data.

(1) Fluid Level Data - The fluid level in a well, determined using an echometer, may be requested by the permits engineer. Ideally, the well has remained shut in long enough for a point of stability approaching static conditions to be reached.

If a reading is obtained before the well has stabilized, the reservoir pressure estimate will be in error and so will the estimated rate of accumulation.

Once the height of the hydrostatic column of liquids present in a well is known, it is possible to estimate the reservoir pressure at that location at a given time.

(2) Well Transient Test Data - The reservoir pressure can be estimated from well test data such as that gathered through **fall off, build up or drill stem tests.** This information can also be used to estimate the reservoir permeability.

v. Estimating the Formation Absolute Permeability, Porosity and Effective Thickness

Permeability, porosity and thickness are reservoir intrinsic properties that greatly affect the amount of produced water which can be injected into the formation.

The more permeable a rock is, the greater its ability to accumulate fluids for a given limiting pressure increment and over a given period of operation. An injection zone in a certain production area may be expected to be more permeable if it is more porous.

The reservoir effective thickness is primarily a function of the rock's permeability and of the perforated interval. If a well has been cased and cemented, the effective thickness may be changed when perforations are added or squeezed off.

The following discussion illustrates the sources of information the Osage/UIC engineers usually explore to obtain the needed permeability, porosity and thickness information.

(1) Laboratory Core Analysis Reports - Core analysis reports usually provide information on permeability determined for core plugs that have been fully saturated with a fluid. The reported values are generally regarded as the absolute permeability for the sampled interval, usually one foot thick.

(2) Well Transient Test Information - It is common practice in reservoir evaluation to use some widely approved engineering methods to estimate permeabilities using information (pressure, fluid flow, elapsed time, etc.) gathered by conducting well transient tests. The permeabilities estimated by these means may have been a function of the saturation of a given fluid in the reservoir at the time the test was run (i.e., relative permeability).

vi. Estimating the Water Viscosity

Though **the water viscosity** is generally assumed to be one centipoise, this viscosity changes with different reservoir characteristics. The water viscosity can be estimated as a function of temperature and pressure using empirical correlations. Information on **the water salinity** (ppm TDS) will also be needed.

vii. Estimating the Zone Of Endangering Influence (ZEI) -

Once the permits engineer has gathered and validated information for all the necessary variables, an analysis of the reservoir pressure response is prepared. The pressure response of interest is affected by the accumulation of fluids in the injection zone during a predefined period of operation.

In the Osage/UIC program, pressures are predicted at certain distances from the injection point(s) using simple algebraic expressions. One expression applies to liquid injection operations and the other applies to gas injection operations.

These equations are greatly simplified solutions to a more complicated mathematical expression which has already been simplified thanks to a number of assumptions.

The computations assume that the reservoir is 100% saturated with the injected fluid and that it is infinite acting at all times. As a result, the answers obtained are approximations.

(1) Identifying the Radial Distance to the Point of Potential Endangerment (REI) - Of special interest to the engineering review are the distances between an identified point with potential for endangerment and one or more injection wells in the area. These interwell distances are permanently defined when an operator stakes a location and drills a well there, fixing in this way the field's well pattern. One of these distances may be found to be the radius of endangering influence (REI) for the permit well or for the field under study, after the mechanical condition of each well has been reviewed.

(2) Computing the Critical Rate of Accumulation - In the Osage/UIC program, the critical rate of accumulation is the number of barrels per day that, over a period of 20 years, would cause the liquids leaking into an identified point with potential for endangerment to rise to the base of the USDWs.

It is possible that, upon meeting certain safety constraints, departures from this basic concept may be warranted.

- Single Injection Well Systems - For a single injection well system, the critical rate of accumulation or environmentally safe rate of accumulation is computed using the distance to the identified point with potential for endangerment as the value for the radius required as input. Smaller radial distances will result in smaller rates of accumulation.

- Multiple Injection Well Systems - Whenever continuity of the injection zone throughout the study area has been established, it will be necessary to estimate **the combined pressure effect of several injection wells** at points with potential for endangerment. Under this flow scenario, **a multiple injection well system** results.

It is very possible that some of the estimated rates of accumulation will become lower as the number of injection wells around a given point of endangerment is increased. The computation process for the described situations can be less demanding with the use of a computer.

viii. Estimating the Maximum Allowable Injection Pressure

Maximum injection pressures are designed to avoid unintentional fracture propagation, thus minimizing the risk of contamination. Revisions of this parameter may be needed throughout the life of a project in order to optimize injection operations.

In the Osage/UIC program, the maximum injection pressure is either estimated using a formation fracturing pressure gradient, or defined as the instantaneous shut in pressure (ISIP) recorded during a well stimulation job.

The following describes how this maximum injection pressure can be estimated using historical well data.

(1) Instantaneous shut in pressures (ISIPs) are considered to be representative of the pressure that would cause a fracture to reopen. These pressure readings may be available from the operator's files, especially for those fields that have pursued aggressive well stimulation programs.

(2) Well Test Data - Because the formation fracture opening pressure may increase with time within an injection project, it may be necessary to modify the permitted maximum injection pressure based on updated information. One approach for updating this information without requiring a new well stimulation job is **the step rate test.** The permits engineer may design and request a step rate test and then proceed to estimate the new maximum allowed injection pressure from the rate and pressure data thus gathered.

c. The Administrative Process

The main objective of the administrative process is to document and communicate the permits engineer's conclusions and recommendations so that they can be reviewed, approved, released to the permittee and implemented in the field.

Following is a discussion on some of the more important documents that make up a permit package.

i. Components of an EPA Osage/UIC Permit

Each permit includes several conditions. The following summarizes some of the more important permit conditions, and the aspect of an injection operation they address.

o Construction Requirements

1. Casing and Cement
2. Wellhead Fittings
3. Tubing and Packer
4. Plugging Requirements

o Operating Requirements

1. Mechanical Integrity
2. Maximum Wellhead Injection Pressure
3. Injected Fluid Type and Purpose
4. Net Injection Rate
5. Fluid Level Monitoring

o Reporting Requirements

ii. Setting Up the Permit Special Conditions

Permit special conditions are based on the analysis by the permits engineer of the information provided by the operator. A summary of some of the more important permit conditions and the type of information associated with their development follows:

(1) Conditions Related to Well Completion and Well Plugging and Abandonment:

- Cement Bond Log
- Cement Tickets
- Caliper Log
- Sacks of Cement
- Cement Additives (Type and Quantity)

(2) Conditions Related to Well Operation

(a) Maximum Injection Wellhead Pressure

- Step Rate Test
- Formation Fracturing Pressure Gradient
- Water Analysis (Specific Gravity)

(b) Rate of Accumulation

- Historical Injection Rates and Pressures
- Water Analysis (Viscosity)
- Well Logs (IEL, CDL/CNL)
- Core Analysis Reports
- Static Fluid Level Data
- Well Transient Tests

iii. Conditions Applicable to All Permits

The Osage/UIC permit package contains a section describing the conditions that are applicable to all permits. Of special interest within this section is the condition on reporting.

iv. The Monitoring Reports

An annual operation report for all injection wells is required by the UIC program. Details on the report submittal schedule are provided in the Annual Operation Report section of this manual.

The requested information on injection rates, pressures and production rates is to be used in the analysis of the reservoir performance as it relates to the periodic reassessment of the potential for endangerment of USDWs.

The following table illustrates one possible way of jointly reporting the monthly rates for the injection and production streams.

	Injection Parameters			Production Parameters	
Month Yr	Avg PSIG	Max PSIG	BBL/Mo.	OIL BPM	WATER BPM

Fluid level monitoring information can be reported in a similar format.

v. Document Preparation and Submittal

A flowchart is presented in Figure 1 to assist in visualizing the document preparation and submittal process.

vi. The Draft Permit, Statement of Basis and Newspaper Notice

(1) The permits engineer prepares a draft permit package consisting of a transmittal letter, a draft permit, a statement of basis and a summary of information to appear in a newspaper notice.

(2) The Source Water Protection Branch Chief then approves the draft permit package by signing the transmittal letter. The package is then sent to the permittee and the comment period opens.

(a) The Comment Period - The permittee has fifteen (15) days following the publication of a newspaper notice to offer comments on the permit conditions.

(b) Response To Comments - At the end of the comment period, response to comments and revisions, if any, are prepared by the permits engineer.

vii. The Final Permit

Next, the Water Quality Protection Division Director signs the permit and a transmittal letter, the permit becomes final and the permit package is forwarded to the permittee.

viii. Authorization to Inject

A letter confirming the verbally granted authorization to inject will be sent the permittee if the well has passed a Mechanical Integrity Test (MIT).

It is a common practice within the Osage/UIC program to require injection wells to be subjected to MITs once every five years. This frequency has been changed to once every three years for those wells that may have required positive pressure monitoring in the tubing/casing annulus.

The Regional Administrator can require a different testing frequency on a case-by-case basis (40 CFR §§147.2920(b)(1)(v) and 147.2920(b)(2)(v)). This allows the prescription of testing frequencies that reflect the risk of mechanical failure in wells, especially in the case of less conventional completions.

ix. Approximate Timeframes

The assessment of the potential for endangerment of the USDWs in enhanced oil recovery operations requires the definition of a dozen or more parameters per well.

When all the back up information can be easily found and validated, and the above parameters can be readily defined, a computer assisted engineering analysis for one injection well may be completed in a few days (less than a week). The time required to complete the engineering analysis may increase in proportion to the increased number of injection wells in the project.

Preparation of the documents in the draft permit package could add from two to three working days to the process. As a matter of policy, the goal is the completion of a single well permit within 45 days from the date the application is received.

There are, however, situations in which it is necessary for the permits engineer to contact the permittee in order to obtain supplemental data. When this is the case, the time for completing a draft permit becomes a function of the time it takes to obtain a satisfactory reply to the engineer's request.

x. Program Contacts

The Osage/UIC program at EPA Region 6 falls under the responsibility of the Ground Water/UIC Section which in turn forms part of the Source Water Protection Branch. This Branch is part of the Water Quality Protection Division.

Following are the officials who have jurisdiction over permitting matters concerning the Osage/UIC program in Region 6:

Director, Water Quality Protection Division	214-665-7101
Chief, Source Water Protection Branch	214-665-7150
Chief, Groundwater/UIC Section	214-665-7165
Chief, Administrative Support Office	214-665-7191

5. Permit Modifications

a. Operator Requested Modifications

An operator can request and obtain a permit modification whenever a reasonable cause exists. The circumstances under which an operator can be granted a permit modification are provided in Section 2927, Part 147 of Title 40 of the Code of Federal Regulations (40 CFR §147.2927).

b. Modifications Initiated by Parties Other Than the Operator

Any interested party may submit to the Regional Administrator a written request for the modification of an Osage/UIC permit. If the Regional Administrator determines that a reasonable cause exists for the permit to be modified, the request may be granted (40 CFR §147.2927(a)(5)).

c. EPA Initiated Modifications

If during the course of a permit review or inspection the Regional Administrator receives information that warrants a permit modification, the permit may be modified. A request from the operator is not needed in this case (40 CFR §147.2927(a)(2)).

6. Plugging and Abandonment

   a. Injection wells must be plugged within one year after cessation of injection operations.

   b. EPA may extend plugging deadline for injection wells if there is a viable plan for future use and no fluid movement into an underground source of drinking water would occur.

   c. Application to Plug

      i. Submit Osage Form No. 139 to the Bureau of Indian Affairs (Osage Agency) and, if plugging an injection well, the Osage UIC Office (EPA) at least five days before planning to plug a well.

      ii. Include outline of plugging procedures or request plugging instructions from the appropriate agency.

      iii. The form submitted to the BIA must include a $15.00 filing fee.

      iv. Table 3 and Figures 2 through 8 summarize plugging requirements for several types of well construction.

   d. After completing plugging:

      i. Cut off the casings and restore the surface location, including removal of junk from the location;

      ii. Submit an Osage form No. 139 which includes a summary of actual plugging procedures and copies of cement tickets to the BIA and, if the well is an injection well, to the Osage UIC Office;

      iii. Request an inspection from the BIA and, if the well is an injection well, the Osage UIC Office.

NOTE: ONLY THE BIA MUST BE NOTIFIED IF A PRODUCTION WELL IS BEING PLUGGED.

Table 3. Plugging Requirements

Current Well Construction	Casings to be Pulled	Plugging Procedure
Surface casing set and cemented at least 50 feet below all USDWs or production casing cemented to surface, AND Production casing cemented above production formation. See Figures 2, 6 and 7	Production casing pulled from at least 50 feet below base of USDWs.	a. Set plug through injection formation to 50 feet above formation. b. Pull production casing from at least 50 feet below base of USDWs. c. Set plug from 50 feet below to 50 feet above surface casing shoe. d. Set plug from 20 to 3 feet subsurface. e. Cut off casing 3 feet subsurface, weld on cap and restore location.
	Production casing not pulled from at least 50 feet below base of USDWs.	a. Set plug through injection formation to 50 feet above formation. b. Part or perforate production casing at least 50 feet below base of USDWs and circulate cement to surface. (Not applicable if production casing is cemented to surface) c. Set plug from 50 feet below to 50 feet above the base of USDWs. d. Set plug from 20 feet to 3 feet subsurface. e. Cut off casings 3 feet subsurface, weld on cap, and restore location.
Surface casing not cemented through all USDWs, AND Production casing cemented above injection formation. See Figures 3, 4, 6 and 7	Production casing pulled from at least 50 feet below base of USDWs.	a. Set plug through injection formation to 50 feet above formation. b. Pull production casing at least 50 feet below base of USDWs. c. Set plug from 50 feet below base of USDWs to 50 feet above surface casing shoe. d. Set plug from 20 feet to 3 feet subsurface. e. Cut off casings 3 feet subsurface, weld on cap, and restore location.
	Production casing not pulled.	a. Set plug through injection formation to 50 feet above formation. b. Perforate or part production casing at least 50 feet below base of USDWs circulate cement behind casing. c. Set plug from 50 feet below to 50 feet above the base of USDWs. d. Set plug from 20 feet to 3 feet subsurface. e. Cut off casings 3 feet subsurface, weld on cap, and restore location.

Table 3. Plugging Requirements (Continued)

Current Well Construction	Casings to be Pulled	Plugging Procedures
No cemented casings. See Figures 7 and 8	Casings pulled.	a. Pull all casings from well. b. Set plug through injection formation to 50 feet above formation. c. Set plug from 50 feet below base of USDWs to 3 feet below surface. d. Restore location.
	Casings not pulled.	a. Squeeze cement through perforations and leave cement plug at least 50 feet above injection formation. b. Perforate all casings set from 50 feet below base of USDWs. c. Circulate cement behind all casings from 50 feet below base of USDWs. d. Set plug from 50 feet below to 50 feet above base of USDWs. e. Set plug from 20 feet to 3 feet subsurface. f. Cut off casings 3 feet below surface, weld cap on casing top, and restore location.

NOTES:

1. Drilling mud must be left between cement plugs.
2. Cement additives cannot be used without approval of EPA engineer.
3. Open perforations above the injection zone must also be properly plugged. Generally, casings must be cemented from 50 feet below to 50 feet above the perforated interval. Discuss specific procedures with the EPA engineer.

Figure 1
Administrative Procedure for Osage UIC Class II Permit and Permit Modification Issuance

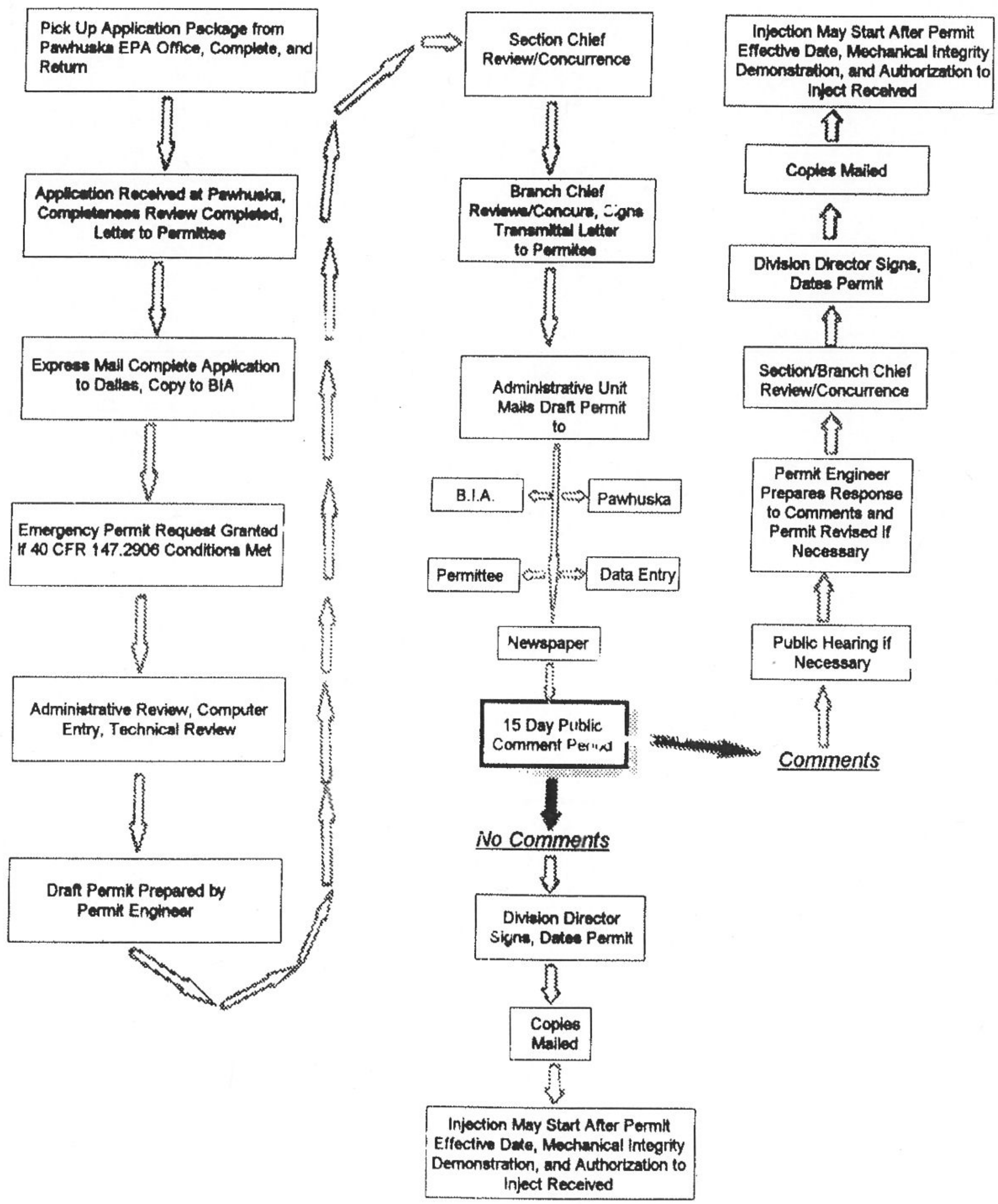


Figure 2
US EPA - REGION 6

Osage/UIC Program

Plugging and Abandonment Requirements
For Wells in Oil and Gas Operations

Surface casing Plugs
(40 CFR 147.2905.(e).(1)
and
(40 CFR 147.2905.(e).(3)

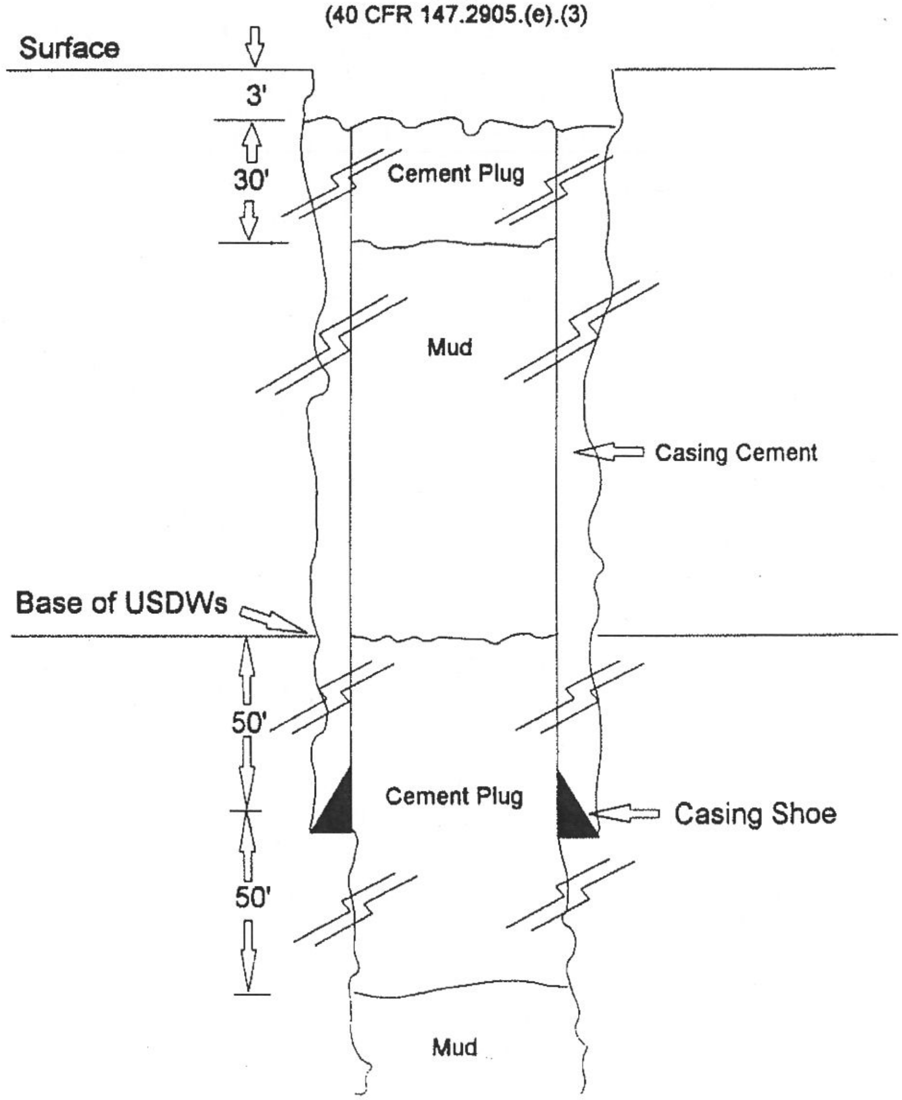


Figure 3
US EPA - REGION 6

Osage/UIC Program

Plugging and Abandonment Requirements
For Wells in Oil and Gas Operations

Surface Casing Plugs
(40 CFR 147.2905.(e).(2) and 40 CFR 147.2905.(e).(3))

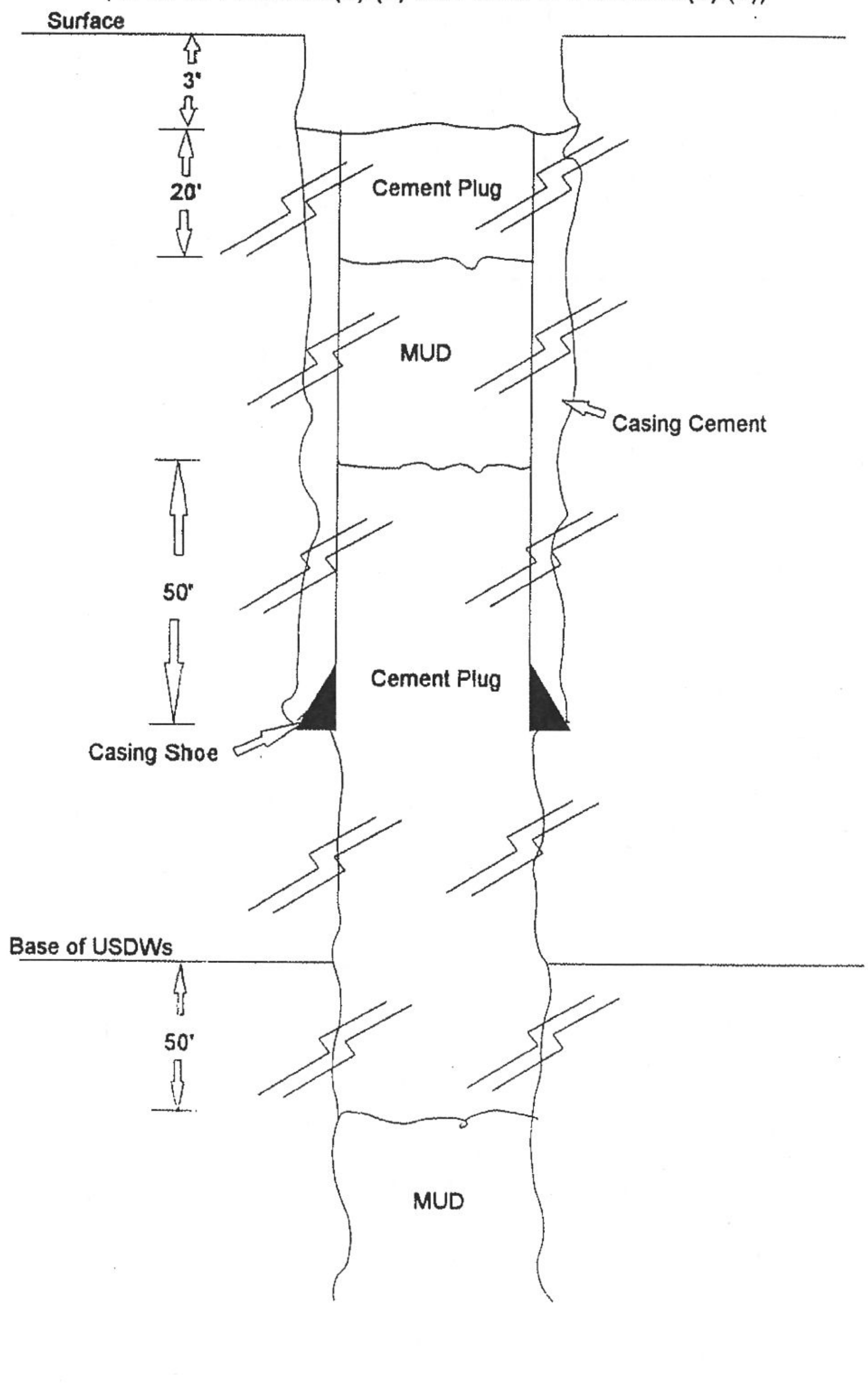


Figure 4

US EPA - REGION 6

Osage/UIC Program

Plugging and Abandonment Requirements
For Wells in Oil and Gas Operations

Plug for Open Hole Section (Below Production Casing Shoe)
(40 CFR 147.2905.(g))

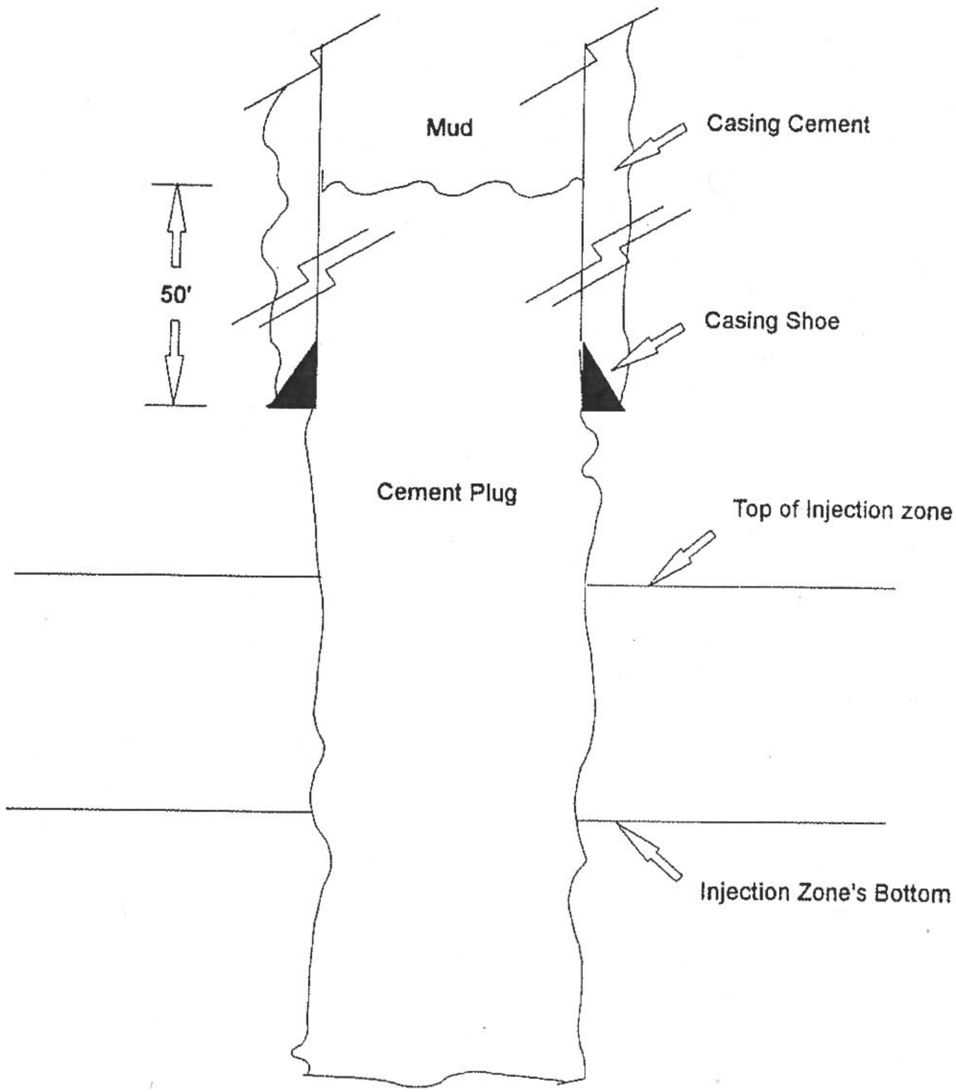


Figure 5

US EPA - REGION 6

Osage/UIC Program

Plugging and Abandonment Requirements
For Wells in Oil and Gas Operations

Plugs for Hole Section With Liner or Screen
(40 CFR 147.2905. (g))

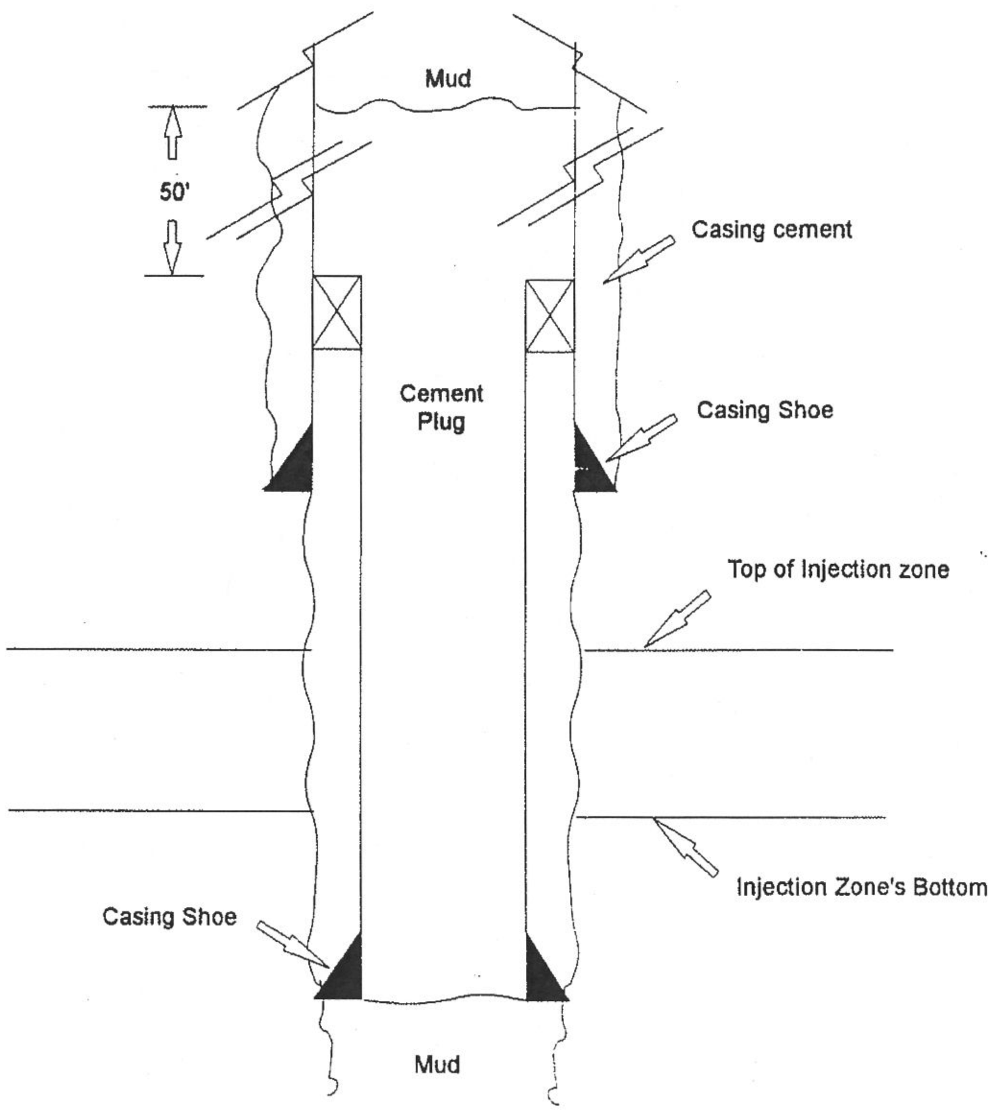


Figure 6

US EPA - REGION 6

Osage/UIC Program

Plugging and Abandonment Requirements
For Wells in Oil and Gas Operations

Plug for Open Hole Section (Below Production Casing Shoe)
(40 CFR 147.2905.(g))

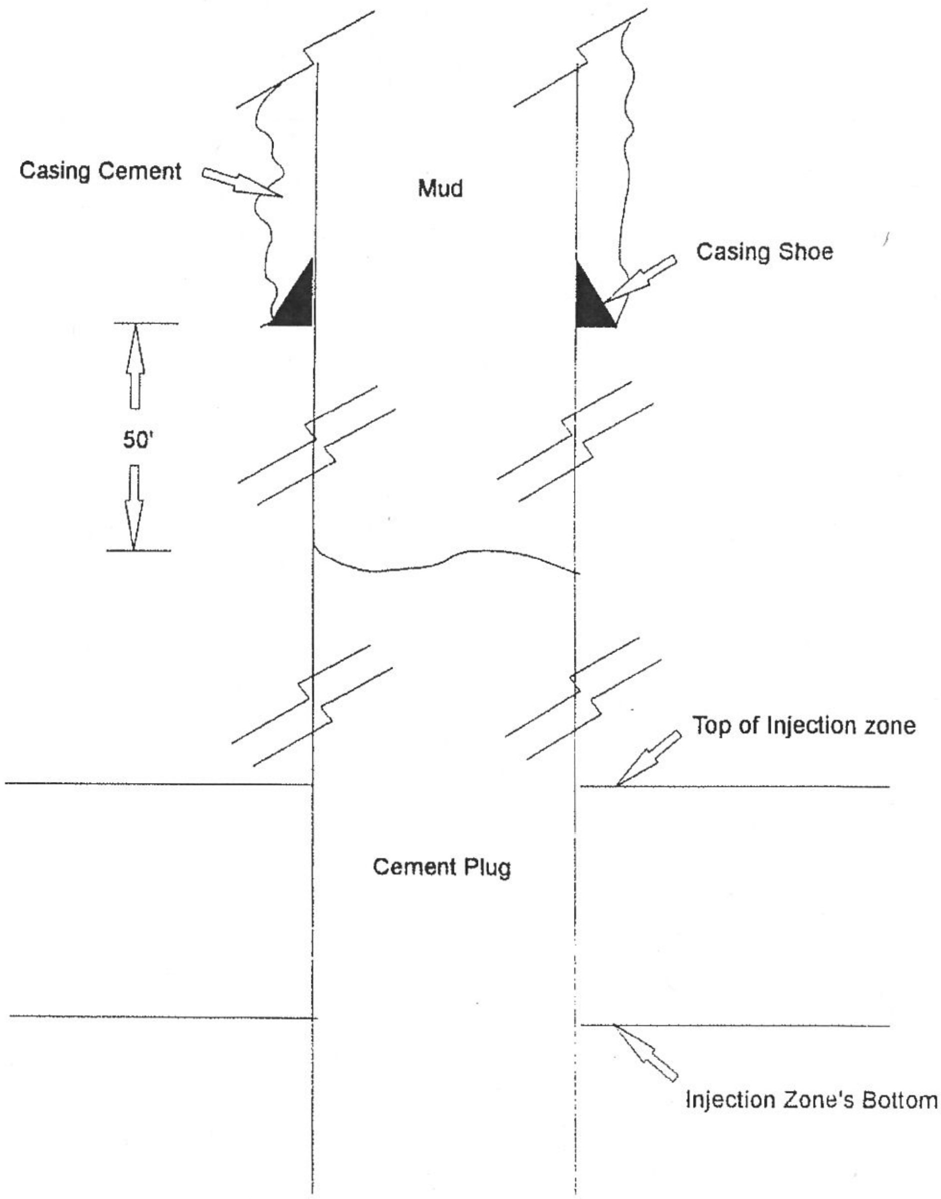


Figure 7

US EPA - REGION 6

Osage/UIC Program

Plugging and Abandonment Requirements
For Wells in Oil and Gas Operations

Plugs for Ripped Production Casing (Cemented)
(40 CFR 147.2905.(f).(2))

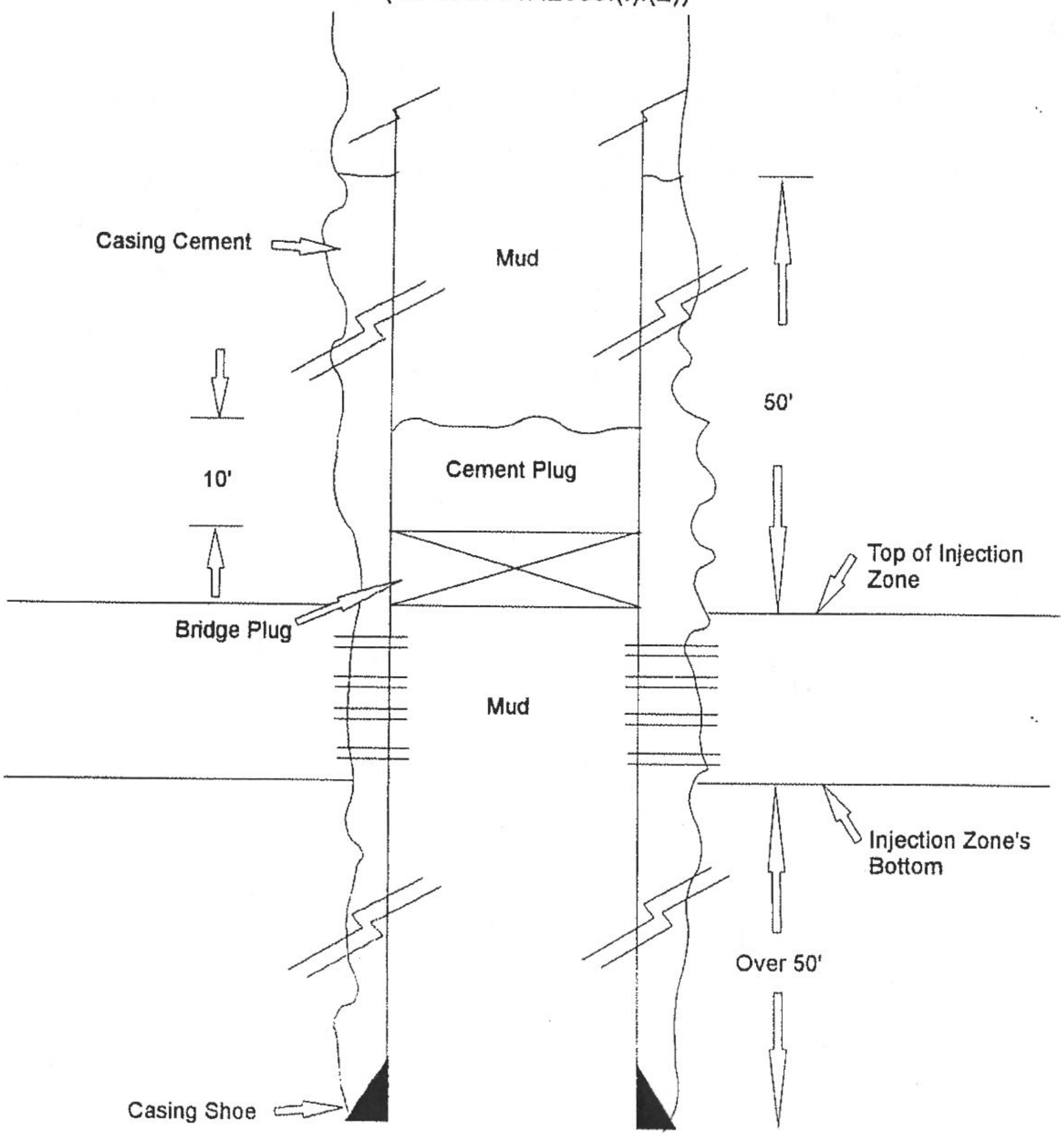


Figure 8

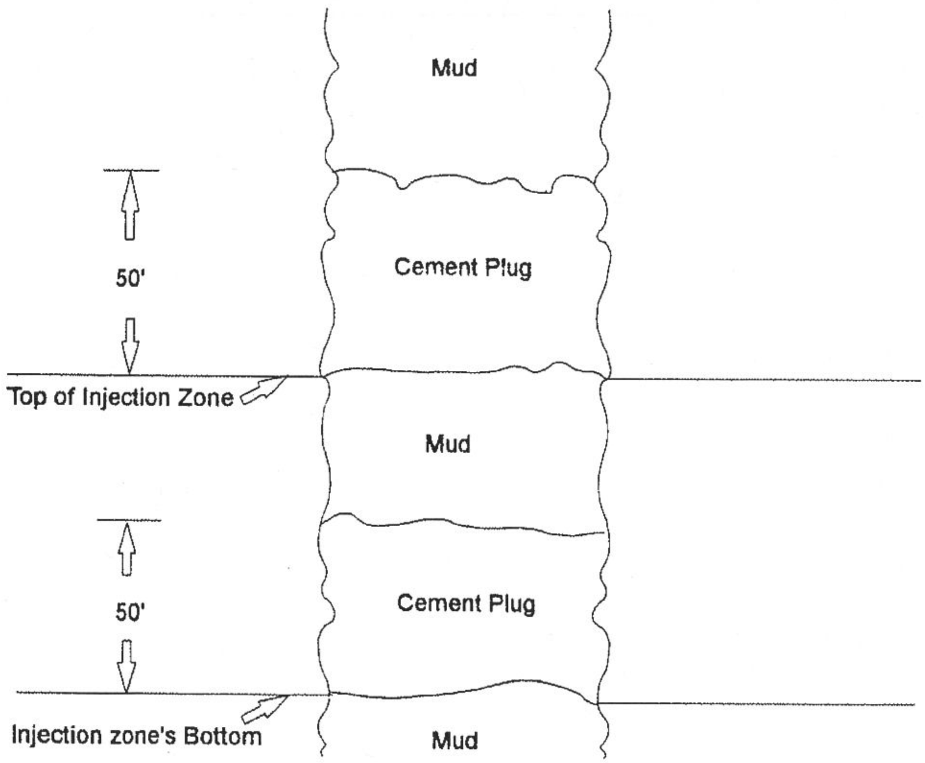
US EPA - REGION 6

Osage/UIC Program

Plugging and Abandonment Requirements
For Wells in Oil and Gas Operations

Plugging and Abandonment Requirements
for Wells in Oil and Gas Operations

Open Hole Section Plugs
(40 CFR 147.2905.(f).(1))



IV. Spill Prevention Control and Countermeasures (SPCC) Regulations

A. Brief Overview of SPCC Regulations 40 CFR 112.7 (Production Facilities)

1. Definitions

An onshore production facility may include all wells, flow lines, separation equipment, storage facilities, gathering lines, auxilliary non-transportation-related equipment, and facilities in a single geographical oil or gas field operated by a single operator.

2. Overview

SPCC regulations apply to facilities that:

a. Have total above-ground storage capacity of 1,320 gallons (31 barrels);

b. Have production facilities having a total underground buried storage capacity of 42,000 gallons or less of oil; and,

c. Could not reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, due to their location.

3. Requirements for Preparation and Implementation of SPCC Plans

a. All facilities that were in operation on January 10, 1974, must have as SPCC Plan prepared and maintained at an appropriate place near or at the facility.

b. A **newly constructed facility** shall prepare a SPCC Plan within *six months* after the date such facility begins operations and shall be fully implemented as soon as possible, but *not later than one year* after such facility begins operations.

4. Guidelines for Implementation of SPCC Plans

a. Dike drain valves shall be closed and sealed at all times, except when rainwater is being drained.

b. Dike area should be inspected prior to discharge.

c. Accumulated oil in drainage areas shall be removed.

d. Tank batteries should have secondary containment that will hold contents of the single largest tank plus precipitation.

e. A program of flow line maintenance should be in place and include: periodic examinations, corrosion protection, flow line replacement and adequate records.

5. Availability, Review, Updates and Certification

a. Onshore production facilities must maintain a complete copy of the Plan at the facility, if manned at least 8 hours per day, or at the nearest field office if unmanned.

b. Each SPCC Plan must be reviewed and certified by a Registered Professional Engineer.

c. The owner or operator is required to amend the Plan for the following reasons:

   i. When required by the EPA after review of the Plan, submitted because of a spill event;

   ii. Whenever there is a change in facility design, construction, operations, or maintenance which materially affects the potential for an oil spill; or

   iii. The owner or operator is required to review each SPCC Plan every 3 years and the SPCC Plan must be amended within 6 months of review, if applicable.

d. The operator must submit the SPCC Plan with any amendments to EPA and to the appropriate State agencies whenever a facility has:

   i. Discharged more that 1,000 U.S. gallons (approximately 24 barrels) into navigable waters in a single spill event; or

   ii. Discharged oil into navigable waters in two reportable spill events within any 12-month period.

e. Within 60 days of the occurrence of either of these two conditions the operator must submit to the EPA Regional Administrator the following: (*Mail to: USEPA Region 6, ATTN: SPCC Coordinator (6SF-RP), 1445 Ross Avenue, Dallas, Texas 75202-2733*)

   i. Amendment of SPCC Plans by Regional Administrator

      (1) Name of facility;

      (2) Name(s) of the owner or operator of the facility;

      (3) Location of facility;

      (4) Date and year of initial facility operation;

      (5) Maximum storage or handling capacity of the facility and current normal throughput;

      (6) Description of the facility, including maps, flow diagrams, and topographical maps;

      (7) A complete copy of the SPCC Plan with any amendments;

      (8) The cause(s) of such spill, including a failure analysis of system or such system in which the failure occurred;

      (9) The corrective actions and/or countermeasures taken, including adequate description of equipment repairs and/or replacements;

(10) Additional preventive measures taken or contemplated to minimize the possibility of recurrence;

(11) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or spill event.

ii. All SPCC Plan amendments, except those proposed by the EPA Regional Administrator, must be certified by a Registered Professional Engineer.

6. Training

a. All operating personnel should be properly trained in operation and maintenance of spill containment and control equipment.

b. Training should be held at intervals frequent enough to ensure adequate understanding of the SPCC Plan.

7. Recordkeeping

a. A log of the release must be recorded in the SPCC Plan for all dike drainage events.

b. Records must be retained according to company policy. However, at a minimum, records for the current and three previous years must be maintained.

8. Civil Penalties

Owners and operators of facilities who violate the requirements of the regulations relating to preparation, implementation, and amendments to SPCC Plans are liable for a civil penalty of not more than $25,000 for each day such violation continues.

B. Sample SPCC Plan Format

SPILL PREVENTION CONTROL & COUNTERMEASURES PLAN

FOR

[NAME OF FACILITY]

[CITY, COUNTY, STATE]

PREPARED BY

[NAME OF PREPARER]

CERTIFIED BY

[NAME OF CERTIFYING PROFESSIONAL ENGINEER]

[MONTH, YEAR]

MANAGEMENT APPROVAL

This Spill Prevention Control and Countermeasures Plan has been prepared and will be implemented in accordance with Section 112.7 of the regulations (40 CFR, Part 112).

____
[Signature of person responsible for the implementation of the SPCC Plan]

______________________ ______________________
[Name] **[Title]**

____
[Address]

__________ __________ __________ __________
[City] **[County]** **[State]** **[Zip]**

______________________ ______________________
[Day Telephone Number] **[After Hours Telephone Number]**

CERTIFICATION

I hereby certify that I have examined the facility, and being familiar with the provisions of 40 CFR, Part 112, attest that this SPCC Plan has been prepared in accordance with good engineering practices.

____
Printed Name of Registered Professional Engineer

(SEAL)

____
Signature of Registered Professional Engineer

Date ______________ Registration No. ______________ State ______________

SPILL PREVENTION CONTROL & COUNTERMEASURES PLAN

1. Name of Facility: ______________________________

2. *If possible* - Latitude: ______________ Longitude: ______________

3. Facility Address: ______________________________

   City: __________ County: __________ State: ________ Zip: __________

4. Facility Contact : ______________________ Title: ______________

   Telephone Number *[If possible -24 hour number]*: ______________

5. *[If different from Facility Contact/Address complete 5 & 6]*
   Name of Owner/Operator: ______________________________

   Corporate Address: ______________________________

   City: __________ County: __________ State: ________ Zip: __________

6. Corporate Contact : ______________________ Title: ______________

   Telephone Number *[If possible -24 hour number]*: ______________

7. Facility start-up date *[date that the facility began operations]*: __________

   Facility AST Storage Capacity *[total capacity of all tanks]*: __________

8. Synopsis of business operations: [Brief description of business activity]:

   ____

9. Route of entry and estimated distance to waterway: [Describe directions (i.e. northwest, south - approximately 500 ft.) to the closest waterway (i.e. Leon Creek, stormdrain, unknown tributary which feeds into Leon Creek to Trinity River):

   ____

   ____

   ____

   ____

10. Has the facility experienced a reportable oil spill event per 40 CFR 110? *[None or 1/18/94 pipe failure 10 bbls.]* If Yes, fill-out Attachment #2, Spill History.

11. Appropriate containment and/or diversionary structure or equipment to prevent discharge oil from reaching a navigable water [check applicable system]

    ________ Dikes, berms or retaining walls sufficiently impervious to contain spilled oil;
    ________ Curbing;
    ________ Culverting, gutters or their drainage systems;
    Weirs, booms or other barriers;
    ________ Retention ponds;
    ________ Sorbent materials.

12. Inspections and Records

(1) The required inspections follow written procedures ____________

(2) The written procedures and a record of inspections, signed by the appropriate supervisor or inspector [See Attachment #3]

Briefly Discuss: ____________

13. Personnel, training and spill prevention procedures

(1) Personnel are properly instructed on the operation and maintenance of equipment to prevent the discharges of oil, and ______ Yes

(2) applicable pollution control laws, rules and regulations. ______ Yes

Briefly Discuss: ____________

(3) Schedule spill prevention briefings for their operating personnel at intervals frequently enough to assure adequate understanding of the SPCC Plan for that facility. [*Such briefings should highlight and describe known spill events or failures, malfunctioning components, and recently developed precautionary measures. (Recommended after each spill event, failure, or malfunctioning or yearly if none occurred)*]
________ Yes

Briefly Discuss: ____________

14. Facility Drainage

(1) Drains for the secondary containment systems at tank batteries and central treatment stations are closed and sealed at all times except when rainwater is being drained? Describe procedures: ____________

2) Prior to drainage, accumulated oil on the rainwater is picked up and returned to storage or properly disposed of? Describe procedures: ______

(3) Field drainage ditches, road ditches, and oil traps, sumps, or skimmers are regularly inspected for oil? Describe procedures: ____________

15. Aboveground tanks

(1) Material and construction are compatible with the oil stored and the conditions of storage? Describe________________

(2) Secondary means of containment appears adequate. ________ Yes
Describe containment:________________

(3) Tank inspections are conducted periodically. *[by appropriate plant personnel; include tank foundation and supports and frequency]*
Frequency? _____ Daily _____ Weekly _____ Monthly _____ Annual _____ Other

Discuss procedures:________________

(4) Tank battery installations "fail-safe" engineered. *[Adequate tank capacity to prevent tank overfill; overflow equalizing lines between tanks; vacuum protection to prevent tank collapse]* Discuss________________

16. Facility transfer operations

(1) Aboveground valves/pipelines examined periodically?
Frequency? _____ Daily _____ Weekly _____ Monthly _____ Annual _____ Other
Discuss procedures:________________

(2) Brine disposal facilities examined often? *[Salt water disposal facilities should be examined often, particularly following a sudden change in atmospheric temperature to detect possible system upsets that could cause an oil discharge]* Describe:________________

(3) Flowline maintenance program established? *[Program should include periodic examinations, corrosion protection, flowline replacements, and adequate records, as appropriate, for the individual personnel]* ____ Yes
Describe:________________

(4) Records of inspection maintained? Where: ________________

C. Sample Notification Procedures Format

Emergency Numbers

Internal Notification Numbers

1. ______________________ Telephone number ______________________
2. ______________________ Telephone number ______________________

External Notification Numbers

1.	National Response Center	(800) 424-8802
2.	EPA Response & Prevention Branch (Dallas)	(214) 665-2222
3.	Osage UIC (EPA)	(918) 287-4041
4.	Osage Bureau of Indian Affairs	(918) 287-1351
5.	Osage Tribal Council	(918) 287-1085
6.	Local Emergency Planning Committee (LEPC)	(918) 287-3980
7.	Local Responders	911

Emergency Response Contractors

1. ______________________ Telephone number ______________________
2. ______________________ Telephone number ______________________

Clean-up Contractors

1. ______________________ Telephone number ______________________
2. ______________________ Telephone number ______________________

Supplies and Equipment

1. ______________________ Telephone number ______________________
2. ______________________ Telephone number ______________________

D. Sample Spill History Format

SPILL HISTORY

The following are any reportable spill(s) occurring from this facility since January 10, 1973.

Name of facility ____________________

Operator ____________________

1. Date__________ Amount (gallons) __________ Cause __________

Affected Navigable Water __________
Corrective action taken __________

Plans for preventing recurrence __________

2. Date__________ Amount (gallons) __________ Cause __________

Affected Navigable Water __________
Corrective action taken __________

Plans for preventing recurrence __________

3. Date__________ Amount (gallons) __________ Cause __________

Affected Navigable Water __________
Corrective action taken __________

Plans for preventing recurrence __________

E. Sample Inspection Logbook Format

RECORD OF INSPECTION

Facility Tank ID#: ________________ **Tank Age:** ____________________ **Max Cap (gal):** __________ **Tank Dia. (ft):** __________ **Tank Hgt (ft):** __________

Check Tank including the base for leaks, specifically looking for:
___ Drips, weeps, & stains ___ Puddles of stored material ___ Corrosion
___ Localized dead vegetation ___ Discoloration of tank ___ Cracks

Check Foundation (mark if present):
___ Cracks ___ Settling ___ Gaps (between tank and foundation)
___ Puddles of stored material ___ Discoloration

Check pipes/valves (mark if present):
___ Leaks at joints, seams, valves ___ Corrosion ___ Discoloration
___ Bowing of pipe ___ Pooling of stored material
___ Ground saturated with stored material

Secondary Containment Types:
___ Dikes/berms/retaining walls ___ Curbing ___ Retention ponds
___ Spill diversion ponds ___ Sorbent Materials (location: ____________)
___ Weirs (location: __________) Other: ____________________

Secondary Containment Checklist:
___ Y ___ N Capacity appears to be adequate?
___ Y ___ N Drainage mechanism manually operated?
___ Y ___ N Sufficiently impervious to stored materials?
___ Y ___ N Presence of stored material within dike or berm?
___ Y ___ N Standing water within dike or berm?
___ Y ___ N Debris within the dike or berm area?
___ Y ___ N Erosion or corrosion of dike or berm (location)?

Tank Construction:
Check Tank including the base of leaks:
Release Prevention Barriers:
Tank Liner:
Tank Safe Fill and Shutdown Procedures:
Release Detection Method:
Check Foundation:
Check Pipes/Valves:
Secondary Containment:
Other comments on the tank, piping appurtenances, foundation, or containment:

Signature of Inspector ______________________________

Signature of Supervisor______________________________

F. Sample Amendment Procedures Format

Amendment of SPCC Plans by Regional Administrator

1. Name of Facility: ____

____

2. If possible, Latitude: ____
Longitude: ______________________________
3. Facility Address: ____

____

City: ______________ County: ______________ State: _____ Zip:
4. Facility start-up date: ____
5. Storage Capacity: ______________ Normal daily throughput: ______________
6. Description of the facility, including maps, flow diagrams, and topographical maps.
7. A complete copy of the SPCC Plan with any amendments *(Enclosed)*.
8. The cause(s) of such spill, including a failure analysis of system or such system in which the failure occurred.
(The failure analysis is to examine and explain the reason for the failure resulting in the spill event. The analysis should be explicit, definitive, and not general.)

____
____
____
____
____
____
____
____

9. The corrective actions and/or countermeasures taken, including adequate description of equipment repairs and/or replacements.

____
____
____
____
____
____
____
____

10. Additional preventive measures taken or contemplated to minimize the possibility of recurrence.

____
____
____
____

11. Such other information as the EPA Regional Administrator may require.

____
____
____
____
____
____
____
____

G. Example Spill Prevention, Control, and Countermeasure Plan

TEX'S BULK STORAGE TERMINAL

100 Everspill Road
Post Office Box 311 (K)
Oily City, USA 12345
Telephone (123) 222-2222

SJ Oil Company
P.O. Box 00002
Crude City, USA 77777

CONTACT
Steve Bob Doe, Manager

CERTIFICATION: I hereby certify that I have examined the facility, and, being familiar with the provisions of 40 CFR Part 112, attest that this SPCC Plan has been prepared in accordance with good engineering practices.

ENGINEER: Christopher Columbus

SIGNATURE:

REGISTRATION NUMBER: 98765 (seal)

STATE: Of the Union

DATE: June 11, 1974

A. NAME OF OWNERSHIP

Name: SJ Oil Company - Tex's Bulk Storage Terminal
100 Everspill Road
P.O. Box 311 (K)
Oily City, USA 12345
Telephone: (123) 222-3333

Manager: Steve Bob Doe
505 Oil Road
Oily City, USA 12345
Telephone: (123) 222-3333

Owner: SJ Oil Company
P.O. Box 00002
Crude City, USA 77000

Other Personnel: Secretary-Bookkeeper
Dispatcher
Transport Driver
Delivery Personnel (3)

Service Area: North-West County

B. DESCRIPTION OF FACILITY

Tex's Bulk Storage Terminal of the SJ Oil Company handles, stores, and distributes petroleum products in the form of motor gasoline, kerosene, and No. 2 fuel oil. The accompanying drawing shows the property boundaries and adjacent highway drainage ditches, buildings on site, and oil-handling facilities.

Fixed Storage:
(2) 100,000-gallon vertical tanks (premium gasoline)
(2) 100,000-gallon vertical tanks (regular gasoline)
(2) 20,000-gallon vertical tanks (No. 2 fuel oil)
(1) 20,000-gallon vertical tank (kerosene)

Total: 460,000 gallons

Vehicles:
(1) Transport truck
(2) Tankwagon delivery trucks

C. POTENTIAL SPILL VOLUMES AND RATES

Potential Event	Volume Released	Spill Rate
Complete failure of a full tank	100,000 gallons	Instantaneous
Partial failure of a full tank	1 to 99,000 gallons	Gradual to instantaneous
Tank overfill	1 to several gallons	Up to 1 gallon per minute
Pipe failure	Up to 20,000 gallons	4 gallons per second
Leaking pipe or valve packing	Several ounces to several gallons	Up to 1 gallon per minute
Leak during truck loading	1 to several gallons	Up to 1 gallon per minute

D. SPILL PREVENTION AND CONTROL

1. Each tank is UL-142 construction (aboveground use).

2. Each tank is equipped with a direct-reading gauge. Venting capacity is suitable for the fill and withdrawal rates.

3. A dike surrounds each tank installation. Each dike wall has been constructed and designed to local, State, and Federal engineering regulations. The contained volume (height versus area) is computed based on the single largest tank within (100,000 gallons) and allowance is made for all additional vertical tank displacement volumes below the dike height (estimated spill liquid level), and for precipitation. A 2-inch water drain is located at the lowest point within the dike enclosure, and it connects to a normally closed gate-valve outside the dike. The gate valve is manually operated. Rainwater contained within this dike is examined prior to release to ensure that harmful quantities of oil are not discharged.

4. After a fill pipe is used, a bucket is placed under it to catch any product that might drip from the pipe.

5. There are no buried or partially buried tanks at this facility.

6. Tanks are subject to periodic integrity testing and inspection. Tank supports, foundations, and piping are included in these inspections, and proper records are kept. The exterior of the tanks are examined frequently.

7. Materials stored on the site for spill countermeasures include bagged absorbent, sorbent pads, and booms. There are sand-filled catchment basins for minor, routine spillage at loading pump intakes and loading racks. The catchment basin will contain greater than the largest compartment of the largest tank truck loaded or unloaded at this facility. Sand will be placed as needed, and any oil-contaminated sand is disposed of properly.

8. Failsafe engineering mechanisms are in place.

   a. Tanks are equipped with high-level alarms.

   b. Tanks are equipped with visual gauges.

E. FACILITY TRANSFER OPERATIONS

1. Buried pipes are properly protected against corrosion. If a section of buried pipe is exposed, it is examined for deterioration.

2. Pipelines not in service or on standby for an extended period are capped or blank-flagged, and marked as to their origin.

3. All pipe supports are properly designed to minimize abrasion and corrosion and to allow for expansion and contraction.

4. Aboveground pipelines are valves are examined periodically to assess their condition.

5. Warning signs are posed as needed to prevent vehicles from damaging pipelines.

6. Curbings are installed at the vehicle loading racks.

F. SPILL COUNTERMEASURES

The front highway drainage ditch on the property's northern boundary crosses the highway through a culvert headed eastward and eventually leads to Carol Creek, located approximately one-half mile away. Emergency containment action will consist of erecting an earthen dam and placing absorbent materials at the entrance to the culvert. Sorbent boom will be strategically placed on Carol Creek, upstream of Dead Duck Pond, to contain oil that will be recovered and disposed of according to generally accepted procedures. Personnel, materials, equipment, are committed to ensuring that this contingency plan is implemented in such a manner that no oil reaches Dead Duck Pond, which is an environmentally sensitive ecosystem.

G. PAST SPILL EXPERIENCE

None.

H. SECURITY

1. The bulk plant is surrounded by steel security fencing, and the gate is locked when the plant is unattended.

2. Tank drain valves and all other valves that will permit direct outward flow of a tank's content are locked in the closed position when not in use. The electrical controls for the pumps are also locked in the closed position when not in use.

3. The loading and unloading connections of pipelines are capped when not in service.

4. Two area lights are located in such a position so as to illuminate the office and storage areas.

I. PERSONNEL

Facility personnel have been instructed by management in the following spill prevention and countermeasure plans:

1. No tanks or compartments are to be filled without checking reserves prior to commencing the filling operation.

2. No pump operations are to continue unless attended constantly.

3. At warning signs at appropriate locations are displayed to remind personnel to check line disconnections before vehicle departures.

4. Training has been held on oil-spill prevention, containment, and retrieval methods. A "dry-run" drill for an on-site vehicular spill has been conducted.

5. Instructions and phone numbers regarding the report of a spill to the National Response Center and the State have been publicized and posted at the office.

6. Instructions and company regulations relating to oil spill prevention and countermeasure procedures have been posted conspicuously.

J. EMERGENCY TELEPHONE NUMBERS

K. NOTIFICATION PROCEDURES

1.	Steve Bob Doe, Facility Manager	(123) 222-3333
2.	National Response Center	(800) 424-8802
3.	State Response Mechanism	(123) 555-2221

L. CLEAN-UP CONTRACTORS

1.	E-Z Clean Environmental	(123) 222-3038
2.	O.K. Engineers, Inc.	(123) 222-2207

M. SUPPLIES AND EQUIPMENT

1.	Oily City Equipment Co.	(123) 222-8372
2.	Northwestern Sorbent Co.	(123) 222-9217

N. REVIEW DATES

6/08/77 (signature)

6/01/80 (signature)

6/10/83 (signature)

6/09/86 (signature)

6/06/89 (signature)

V. Migrating Birds

Migratory Bird Protection

In 1918, the United States Congress enacted the Federal Migratory Bird Treaty Act which provides for the controlled harvest and protection of migratory birds. The Act makes the illegal death of any migratory bird a violation of Federal law, punishable by up to $10,000 in fines and possible criminal prosecution. The law is enforced by the U.S. Fish and Wildlife Service, a branch of the U.S. Department of the Interior.

The enforcement of this Act has increased in recent years with several operators being found guilty of illegally taking or killing migratory birds which have been injured or killed as a result of contact with oil or saltwater in pits or open tanks. Nearly all birds of the Mid-Continent area are protected under the Act, including the common sparrow.

Requirements

Open top tanks and pits of a permanent nature, such as skimming pits or emergency saltwater storage pits which are required to be netted, screened, or covered may utilize several different methods.

Open top tanks can be fitted with a solid cover made of wood, steel, or fiberglass, or can be covered with a screen or net. Chicken wire can be used for this, but is cumbersome to work with and does not last very long. Polypropylene netting with a 1-inch mesh size is a popular installation for open top tanks. The 1-inch mesh is needed to prevent small birds from getting through the net.

The best way to cover pits is with the polypropylene net using some sort of tie down and support system to secure the net. Securing the net extends its life. Several companies in the area have the capability to furnish and install protective netting, or field personnel can also install the nets in most cases.

VI. Naturally Occurring Radioactive Material (NORM)

Naturally Occurring Radioactive Materials, also known by the acronym NORM, are natural materials which spontaneously emit ionizing radiation. NORM is found throughout our environment (e.g., certain building materials, fertilizers, sun, etc.) as well as in association with some oil and gas production operations.

Since the primary radioactive element is soluble in water, it is carried in the produced water from the reservoir to the surface. When present, NORM will most commonly be found where scale and sludge deposits in surface equipment such as separators, heater treaters, pumps, tubing, etc. Therefore, surveys should be conducted on all surface equipment prior to any maintenance activities until it has been determined that NORM is not present from that specific reservoir.

When employees are performing maintenance activities on equipment that may contain NORM, employees should abide by the following:

1. Do not eat, drink, smoke, dip or engage in any other ingesting activities while working on equipment containing NORM until they are removed from the area, and hands and faces have been thoroughly washed with copious quantities of soap and warm water;

2. Keep open cuts and sores covered;

3. Keep hands away from eyes and mouth while working or when wearing protective gloves or other equipment;

4. Wear appropriate clothing and protective equipment as instructed by health and safety officials.

NOTE: There are no Federal Laws at the time of this printing, dealing with NORM. However, this information is presented to make you aware that caution should be taken if NORM is encountered.

VII. Resource Conservation and Recovery Act

A. Exploration and Production Waste Exemption[1]

The EPA Resources Conservation and Recovery Act has exempted certain wastes associated with the exploration and production of crude oil, natural gas, and geothermal resources from hazardous waste rules. However, the exemption is limited in scope and does not cover all waste material generated in the oil field. EPA recognizes that the oil field produces large volumes of waste that are typically non-toxic, or have a low toxicity value. As such, EPA has exempted wastes that are "intrinsic to and uniquely associated with oil and gas exploration."

To understand the scope of the exemption it is necessary to understand the basic principle used by the EPA to distinguish between exempt and non-exempt wastes. A simple rule of thumb for determining the scope of the exemption is whether the waste in question has come from down-hole or has otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product. If the answer to either question is yes, the waste is most likely considered exempt.

Examples of exempt waste include produced water, drill cuttings, gylcol filters, iron sponge waste, anti-hydrate chemicals, and drilling fluids. It is important to recognize that the EPA exemption does not apply to transportation wastes. Specifically, the exemption no longer applies after the crude oil has changed custody, or after the crude oil leaves the initial point of oil-water separation in the field.

Exempt wastes generated within the oil field do not need to be tested for hazardous waste characteristics (toxicity, ignitability, reactivity, and corrosivity) provided they have not been commingled with non-exempt wastes--this includes spill of crude oil and produced water. This is an important distinction because often times chemicals may be present in the oil field that will cause the exemption to be lost if exempt and non-exempt wastes are commingled, handled incorrectly, or disposed of improperly. (For example, paints, solvents, pipe dope, and lube oils may be used at an oil well but they are not considered to be "intrinsic an uniquely" associated with production.) Therefore, if waste products from painting are disposed of in a reserve pit, the drill cuttings in the reserve pit lose their exemption and the reserve pit contents must be tested for hazardous characteristics before disposal and the proper disposal method used based on the test. Conversely, pipe dope and lube oil may come into contact with produced water and crude oil during the course of exploration or production activities but this would not generate a non-exempt waste. (However, if pipe dope or used lube oil is disposed into an exempt waste stream, then the entire stream must be tested. **Simply stated, mixing an exempt waste with a no-exempt waste would cause the exempt waste to loose its exempt status, and in some situations could generate a large volume of hazardous waste.**)

A list of exempt and non-exempt waste is on the following page.

Exempt E&P Wastes

- Produced water
- Drilling fluids
- Drill cuttings
- Rigwash
- Drilling fluids and cuttings from offshore operations disposed of onshore
- Geothermal production fluids
- Hydrogen sulfide abatement wastes from geothermal energy production
- Well completion, treatment, and stimulation fluids
- Basic sediment and water and other tank bottoms from storage facilities that hold product and exempt waste
- Accumulated materials such as hydrocarbons, solids, sands, and emulsion from production separators, fluid treating vessels, and production impoundments
- Pit sludges and contaminated bottoms from storage or disposal of exempt wastes
- Gas plant dehydration wastes, including glycol-based compounds, glycol filters, filter media, backwash, and molecular sieves
- Gas plant sweetening wastes for sulfur removal, including amines, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge
- Workover wastes
- Cooling tower blowdown
- Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)
- Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation
- Produced sand
- Packing fluids
- Hydrocarbon-bearing soil
- Pigging wastes from gathering lines
- Wastes from subsurface gas storage and retrieval, except for the non-exempt wastes listed below
- Constituents removed from produced water before it is injected or otherwise disposed of
- Liquid hydrocarbons removed from the production stream but not from oil refining
- Gases from the production stream such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons
- Materials ejected from a producing well during the process known as blowdown
- Waste crude oil from primary field operations
- Light organics volatilized from exempt wastes in reserve pits or impoundments or production equipment

Non-exempt E&P Wastes

- Unused fracturing fluids or acids
- Gas plant cooling tower cleaning blowdown wastes
- Painting wastes
- Waste solvents
- Oil and gas service company wastes such as empty drums, drum rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids
- Vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste
- Refinery wastes
- Liquid and solid wastes generated by crude oil and tank bottom reclaimers[1]
- Used equipment lubricating oils
- Waste compressor oil, filters, and
- Used hydraulic fluids
- Waste in transportation pipeline related pits
- Caustic or acid cleaners
- Boiler cleaning wastes
- Boiler refractory bricks
- Boiler scrubber fluids, sludges and ash
- Incinerator ash
- Laboratory wastes
- Sanitary wastes
- Pesticide wastes
- Radioactive tracer wastes
- Drums, insulation, and miscellaneous solids

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[1]**NOTE:** Although non-E&P wastes generated from crude oil and tank bottom reclamation operations (e.g., waste equipment cleaning solvent) are non-exempt, residuals derived from exempt wastes (e.g., produced water separated from tank bottoms) are exempt. For a further discussion, see the Federal Register notice "Clarification of the Regulatory Determination for Wastes from the Exploration,